STUDY OF SOUTH CAROLINA ELECTRIC AND GAS COMPANY FUEL EXPENSES

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(ANNUAL REVIEW OF BASE RATES FOR FUEL COSTS)

Prepared by

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Background

Pursuant to the Settlement Agreement in the *Annual Review of Base Rates for Fuel Cost of South Carolina Electric & Gas Company ("Company")*, the South Carolina Office of Regulatory Staff ("ORS") has performed a study of the Company's fuel purchasing methods. The study generally encompasses the review period of January 2005 through December 2006. This study examines the Company's fuel-related activities and evaluates the reasonableness of its practices. Specifically, this study and analysis include the following subject matters with respect to fuel expenses: Fuel Procurement, Transportation of Fuel, Fuel Mix, Purchased Power and Off-system Sales, Affiliate Transactions, Hedging Activities, Inventory Storage, Generation Planning, and ORS Site Visits.

The Company is a regulated public utility engaged in the generation, transmission, distribution, and sale of electricity to approximately 592,000 retail and wholesale customers in South Carolina. It is the principal subsidiary of SCANA Corp., an $8 billion Fortune 500 energy-based holding company, headquartered in Columbia, SC. The Company maintains the operation of a diverse mix of power generating units to include, fossil, hydro, gas turbines (both simple and combined cycle), and nuclear power. Collectively, these units are capable of producing approximately 6,000 MW of power. These units are geographically located throughout the Company's service territory in South Carolina (See Attachment A).

Fuel Procurement

Long-Term Contracts

The Company's primary source of energy generating fuel is coal. During the review period, the Company secured several long-term coal contracts to ensure an adequate supply of fuel (See Attachment B). The contracts vary in term ranging from 2 yrs to 4.7 years. The annual tons secured by the contracts range from 240,000 tons to 840,000 tons resulting in approximately 6.5 million tons of contract coal to be delivered annually (See the Inventory Management Section for more detail). The Company procures coal with the following typical specifications:

- Moisture: 7.0% (maximum)
- Ash: 12.0% maximum (less than 10.0% preferred)
- Sulfur: 1.0% maximum
- Volatile: 30-35%
- Btu/lb: 12,500 minimum
- Ash Fusion (Reducing Atmosphere):
  - Initial Deformation Temperature: 2400 °F minimum
  - Fluid Temperature: 2700 °F minimum
- Hardgrove Grindability Index: 42-60
- Size: 2" x 0"
- Fines: 50% maximum

The coal contracts for [redacted], [redacted], [redacted], [redacted], [redacted], and [redacted] show a price increase during the term of the contracts. When comparing the initial producer price to the current producer price, the increases per ton were 5.5%, 57%, 1.8%, 33%, 52%, and 19%, respectively. Most noteworthy, the [redacted] contract shows a 57% increase in price and the greatest quantity to be supplied to the Company, 840,000 annual tons. These price increases reflect contract re-negotiations which coincided with market price increases for coal.

The Company primarily transports coal via the CSX railroad system from the Central Appalachia Coal Region (Eastern Kentucky, Western Virginia, Eastern Tennessee, and West Virginia). Twelve of the 13 long-term contracts utilize the CSX rail system. [redacted] is the only producer under a long-term contract with the Company that utilizes the Norfolk Southern (NS) rail system.

The [redacted] system has a transportation cost of $[redacted]/ton. In contrast, the [redacted] rail system has a noticeably less expensive average transportation cost of $[redacted]/ton. A comparison reflects a [redacted]% higher transportation cost including fuel surcharge for [redacted]. Consequently, the [redacted] contract results in the most expensive delivered coal at $[redacted]/ton. The Company, aware of the higher transportation cost for the [redacted] rail system, ultimately elected to contract with [redacted] to enhance delivery diversity and help ensure greater reliability of its primary fuel. (See the Transportation of Fuel Section for more details on the performance of the [redacted] railroad.) It should be noted that although the [redacted] contract supplies the most expensive coal to the Company's system, the [redacted] contract represents only 360,000 annual tons or 5% of the overall system purchases. The overall system purchases were 6,976,000 contracted annual tons.

ORS compared each long-term contract price to the corresponding actual spot market price at the time the contract was let. This approach allowed ORS to evaluate the Company's success in negotiating advantageous conditions for its long-term coal contracts. The comparison revealed that all contracts reflect coal prices lower than the corresponding spot market price for coal, at the time the contracts were let. Table 1 below shows the results of the comparison.

Table 1 – Long-Term Contract Price v. Actual Spot Market Price

Producer	Initial Contract Date	Tons (Annual)	Initial Contract Price	[1]Spot Mrkt Price	$ Difference	% Difference
[redacted]	8/1/2003	600,000	$32.90	$33.80	-$0.90	-2.66%
[redacted]	1/1/2005	600,000	$45.50	$66.50	-$21.00	-31.58%
[redacted]	4/1/2004	360,000	$46.50	$57.25	-$10.75	-18.78%
[redacted]	4/1/2004	240,000	$45.50	$57.25	-$11.75	-20.52%
[redacted]	1/1/2001	840,000	$26.56	$28.00	-$1.44	-5.14%
[redacted]	3/1/2005	300,000	$52.00	$62.35	-$10.35	-16.60%
[redacted]	1/1/2005	240,000	$52.00	$66.50	-$14.50	-21.80%
[redacted]	12/1/2004	648,000	$53.00	$66.50	-$13.50	-20.30%
[redacted]	9/1/2003	240,000	$32.50	$34.80	-$2.30	-6.61%
[redacted]	1/1/2004	600,000	$33.00	$39.00	-$6.00	-15.38%
[redacted]	8/1/2003	528,000	$33.00	$33.80	-$0.80	-2.37%
[redacted]	9/1/2001	720,000	$33.00	$44.00	-$11.00	-25.00%
[redacted]	9/1/2001	600,000	$36.00	$44.00	-$8.00	-18.18%

[1]**Source:** Energy Information Administration - US Department of Energy

Short-Term Spot Contracts

During the review period, the Company secured 17 spot contracts for coal to supplement its existing long-term contracts, for inventory management and to take advantage of current market conditions (See Attachment C). The contracts vary in term ranging from 1 month to 5 months. The annual tons secured by the spot contracts range from 10,000 tons to 100,000 tons resulting in approximately 460,000 tons of spot contract coal to be delivered in 2005. The Company reports to ORS it will consider 2006 spot purchases as such purchases become necessary. The physical properties of the spot contract coal meet the same standard specifications as for the long-term contacts, described above, but may also take advantage of off-specification coal products.

As with its long-term contracts, the Company primarily transports its spot coal via the CSX railroad system from the Central Appalachia Coal Region. Eleven of the 17 spot contracts utilize the CSX rail system. However, the [redacted], [redacted], and [redacted] spot coal contracts utilize the NS rail transportation system. The NS system has a transportation cost for these contracts of $[redacted]/ton, $[redacted]/ton, and $[redacted]/ton, respectively including fuel surcharge. This reflects an average transportation cost of $[redacted]/ton for [redacted]. In contrast, the [redacted] rail system has a [redacted] average transportation cost of $[redacted]/ton. A comparison reflects a [redacted] transportation cost for [redacted]. The above spot contracts transported on the NS rail system, collectively, represent 90,000 tons or 20% of the total spot contract quantity purchased for the system.

The [redacted] spot contract for off-shore coal is the most expensive "delivered" coal purchase at $[redacted]/ton. Similarly, the [redacted] and the [redacted] spot coal contracts are also off-shore coal purchases and reflect a delivered cost of $[redacted]/ton and $[redacted]/ton, respectively. Off-shore coal contracts reflect a significantly higher producer price in comparison to a domestic coal price. In the first 7 months of 2005, 170,000 tons or 37% of the total spot contract quantity was purchased from off-shore coal markets. These purchases were primarily made to supplement declining inventories.

Additively, the off-shore coal purchases (170,000 tons or 37%) and the contracts that utilized the NS transportation system (90,000 tons or 20%) supplied 260,000 annual tons or 57% of the spot contract coal to the Company in 2005. Although these contracts represent expensive coal purchases, the quantity of 260,000 annual tons represents only 3.7% of the overall system purchases.

The Company, aware of the higher costs of off-shore coal, ultimately pursued off-shore purchases to off-set tardy and non-delivered coal shipments via the [redacted] rail system. The Company also entered into contracts with suppliers that utilize the more expensive [redacted] rail system to gain an alternate supply path for coal. (See the Transportation of Fuel Section for more details on the performance of the [redacted] railroad).

ORS compared each spot contract price to the corresponding actual spot market price at the time the contract was let. This approach allowed ORS to evaluate the Company's success in negotiating advantageous terms for its short-term coal contracts. The comparison revealed that 14 of the 17 contracts reflect coal prices lower than the corresponding spot market price for coal, at the time the contract was let. However, the [redacted], [redacted], and the [redacted] contracts reflect prices above the market value for coal. The contract prices are $[redacted]/ton ([redacted]%), $[redacted]/ton ([redacted]%), and $[redacted]/ton ([redacted]%) above the corresponding spot market price, respectively. Table 2 below shows the results of the comparison.

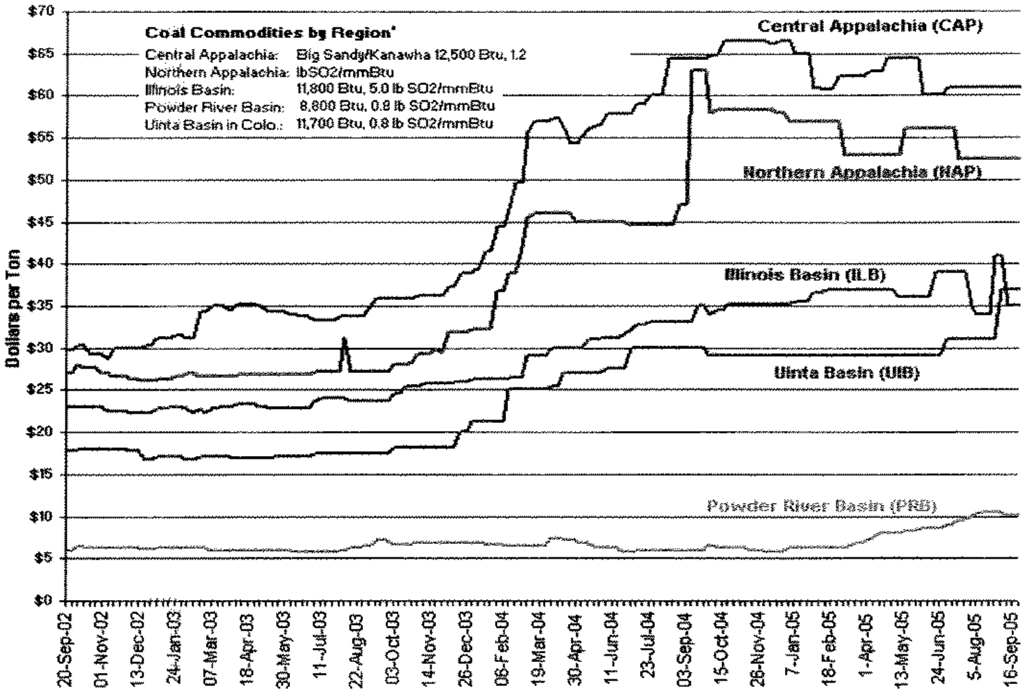
Table 2 – Short Term Spot Contract Price v. Actual Spot Market Price

Producer	Contract Date	Tons (Annual)	Current Producer Contract Price	[1]Spot Mrkt Price	$ Difference	% Difference
[redacted]	2/1/2005	50,000	$73.62	$61.00	$12.62	20.69%
[redacted]	1/1/2005	20,000	$53.50	$66.50	-$13.00	-19.55%
[redacted]	2/1/2005	20,000	$55.00	$61.00	-$6.00	-9.84%
[redacted]	2/1/2005	20,000	$54.00	$61.00	-$7.00	-11.48%
[redacted]	2/1/2005	50,000	$54.00	$61.00	-$7.00	-11.48%
[redacted]	3/1/2005	10,000	$54.25	$62.35	-$8.10	-12.99%
[redacted]	2/1/2005	10,000	$54.87	$61.00	-$6.13	-10.05%
[redacted]	3/1/2005	10,000	$56.00	$62.35	-$6.35	-10.18%
[redacted]	3/1/2005	20,000	$56.00	$62.35	-$6.35	-10.18%
[redacted]	3/1/2005	10,000	$59.00	$62.35	-$3.35	-5.37%
[redacted]	6/1/2005	20,000	$54.00	$60.00	-$6.00	-10.00%
[redacted]	6/1/2005	20,000	$56.00	$60.00	-$4.00	-6.67%
[redacted]	6/1/2005	10,000	$54.55	$60.00	-$5.45	-9.08%
[redacted]	7/1/2005	20,000	$64.00	$61.00	$3.00	4.92%
[redacted]	7/1/2005	10,000	$52.00	$61.00	-$9.00	-14.75%
[redacted]	7/1/2005	100,000	$69.95	$61.00	$8.95	14.67%
[redacted]	7/1/2005	60,000	$54.00	$61.00	-$7.00	-11.48%

[1]**Source:** Energy Information Administration - US Department of Energy

As noted above, the [redacted], [redacted], and the [redacted] contracts reflect off-shore purchases to off-set tardy and non-delivered coal shipments via the [redacted] rail system. (See the Transportation of Fuel Section for more details on the performance of the [redacted] railroad.) Also, it should be noted that during the review period, coal prices experienced unprecedented increases. Graph 1 below illustrates the increasing price for coal by geographic region over the 3 year period ending September 2005. Notwithstanding the adverse market conditions and circumstances described above, the Company should only consider purchasing coal from expensive off-shore markets as a last alternative to acquire fuel or only when it has a competitive delivered price with domestic coal.

Graph 1 – Coal Commodities by Region



Source: Energy Information Administration - US Department of Energy (10.03.05)

Procurement Process

ORS reviewed the Company's Fossil Fuel Management Policy for Coal Procurement. The policy includes a formal hierarchical signature approval structure and requires a review by the Company's Risk Management Oversight Committee when required. The major components of the policy are outlined in Attachment D.

Based on inventory status and contract expiration dates, the Company periodically issues solicitations to secure long-term contracts and/or spot purchases to manage inventory levels. The Company evaluates the bids received in accordance with their internal bidding process. This evaluation is based on tonnage offered, coal price, freight price, delivered cost per Mbtu, prior experiences with supplier, coal specifications, qualities, and method of transportation. The

Company also evaluates additional criteria before awarding a contract. These criteria include producer past performance, producer financial stability, condition of the market, etc.

Natural Gas-Fueled Power Plants

The Company operates two major natural gas-fueled power plants, Jasper Station and Urquhart Station. The Jasper Station, a combined-cycle plant, is supplied natural gas via access to the Elba Island liquid natural gas terminal and transported through the Southern Natural Pipeline and the SCG Pipeline interstate systems. The Urquhart power plant consists of two combined-cycle units. This power system is supplied natural gas via access to the Gulf Coast natural gas production region and transported through the Southern Natural Pipeline interstate and the SC Pipeline intrastate systems.

The Company has established a formal procurement process for natural gas in an attempt to ensure an adequate and reliable supply for its two major gas-fueled power plants. The Company continuously monitors anticipated fuel needs and secures fuel delivery accordingly. The monitoring process consists of four opportunities to nominate natural gas during a 24-hour purchase window. Natural gas is subsequently purchased in accordance with their internal procurement approval procedures.

Regarding the purchase of natural gas to supply the Jasper and Urquhart plants, ORS audited a sample of the daily purchases. The audit documented that for the review period the daily prices paid for the Company's natural gas purchases fell within the range of natural gas prices at the Southern Natural, Louisiana receipt point as reported in Gas Daily for the applicable purchase dates. Additionally, ORS's audit documented that purchases were made in accordance with the applicable guidelines of their executed contract with Southern Natural and SCG Pipeline (Jasper only) and that the applicable charges from these interstate pipeline companies were charges identified in their FERC approved tariffs.

Most recently, the Company realized a net annual savings of interstate capacity ([redacted] and [redacted] Pipeline) reservation charges of $1,698,420 or an 11% reduction of the total capacity reservation charges to the Jasper facility. This savings opportunity was the result of a Memorandum of Understanding signed between the Company's electric and gas operations in the Annual Review of the Gas Purchasing Policies of SCE&G (Docket No. 2005-5-G). This Memorandum of Understanding as approved by Commission Order 2005-653 provides for the capacity cost to be shared or allocated (the allocation is based upon firm/retail customer percentages) between the two operation at 67.68% applicable to the electric operations and 32.32% applicable to the natural gas operations.

Synthetic Fuel

The Company partners in SC CoalTech #1 and CoalTech #1 for the production of synthetic fuel at its Wateree and Canadys power stations, respectively. The synthetic fuel, or synfuel, is produced by adding a binding agent to raw coal to create a "significant chemical change" to the fuel. The Wateree plant operation is capable of producing approximately [redacted] per year of synfuel. Varying quantities are then distributed to the Wateree, Cope, and McMeekin plants. Approximately [redacted] per year of synfuel is produced at the Canadys plant. Varying quantities are then distributed to the Canadys and Cope plants. The Canadys synfuel is also sold to various industries. The synfuel is sold back to the Company by the partnerships at a $[redacted]/ton reduction in price, and in addition, qualifies for federal tax credits. More specifically, the Company's portion of the tax credits generated by the synfuel processes are accumulated as a liability on the Company's balance sheet. In 2005, approval was given by the Commission for the tax credits to be used to offset the $275 million capital costs associated with the construction of the back-up dam at Lake Murray. The use of synfuel has benefited the Company as well as the rate payers.

In summary, during the review period, the entire industry as well as the Company experienced significant price increases due to the upward market trend for coal. The Company and the industry in general also experienced delivery difficulties under its primary railroad contract. Notwithstanding the adverse market conditions and circumstances described above, the Company should only consider purchasing coal from expensive off-shore markets as a last alternative to acquire fuel or only when it has a competitive delivered price with domestic coal. The Company also has been innovative by pursuing the use of synthetic fuel. The Company should continue to evaluate and take advantage of alternative fuels as they become practical. Also, the Company should continue to monitor new technology and its potential benefits as technology evolves. In particular, the Company should investigate the feasibility of on-site coal/petroleum coke gasification. The US Department of Energy reports of a successful cost effective project in Florida and Indiana (See Attachment E). Lastly, the Company should closely evaluate the potential of blending coal on-site at its power stations. Such practices inherently enhance fuel practices and directly benefit the Company's performance.

Transportation of Fuel

As mentioned above in the Fuel Procurement Section, the Company primarily utilizes the CSX railroad system to transport coal to its power generating facilities. The Company also maintains one transportation contract with Norfolk Southern railroad system to ensure delivery diversity, enhance reliability, and assist in maintaining adequate inventories (See Table 3, below).

Table 3 – Railroad Transportation Contracts

Contract No.	Transporter	Term	Description
[redacted]	[redacted]	[redacted]	Main Coal Contract - System Purchases
[redacted]	[redacted]	[redacted]	[redacted] Short Rail Contract - Primarily to [redacted]
[redacted]	[redacted]	[redacted]	Synfuel Transportation
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	Incentive Contract - Complements [redacted]
[redacted]	[redacted]	[redacted]	[redacted] Contract to [redacted]

The Company primarily transports coal for its system of power plants under the [redacted] contract [redacted]. This contract works in concert with [redacted] contract [redacted], which provides [redacted]. The [redacted] contract [redacted] expired on 9/30/05 and [redacted].

During the review period, the Company also incurred fuel costs associated with rail and/or truck transportation for spot purchases. The average cost is $[redacted]/ton (See Attachment C). This average cost reflects the transportation of the coal from the off-loading Port of Charleston to its final destination, the Williams Station power plant. As mentioned in the Fuel Procurement Section, the Company utilized shipments on three short-term spot contracts during the review period. The costs of the coal plus the transportation to the plant collectively represent the most expensive coal purchases by the Company.

As mentioned in the Fuel Procurement Section above the Company entered directly into a contract with the more expensive railroad service provider, [redacted]; purchased more expensive off-shore coal; and entered into contracts with suppliers that utilize the more expensive [redacted] rail system. These actions were in response to tardy and non-deliveries by [redacted]. As of October 2005, the Company had yet to receive 16 scheduled shipments/trains or approximately 160,000 tons of coal from [redacted]. Table 4, below, provides a month by month summary of the [redacted] rail system performance.

Table 4 – 2005 [redacted] Transportation Performance Summary

Month	Requested	Scheduled	Delivered	Delta
Jan	56	56	50	-6
Feb	55	55	49	-6
Mar	71	71	54	-17
Apr	55	55	41	-14
May	57	57	44	-13
Jun	62	62	48	-14
Jul	54	54	43	-11
Aug	55	55	47	-8
Sep	59	59	45	-14
Oct	57	56	40	**-16**
			Average Delta =	-12

A review of transportation costs during the period of April 2004 through June 2005 revealed that the Company has secured less expensive transportation contracts when compared to the two other major investor-owned utilities operating in South Carolina, Duke Power and Progress Energy Carolinas. Table 5 below shows an average freight cost of $13.04/ton for the Company. Currently, the Duke Power Company and Progress Energy Carolinas show 29% and 27% higher average transportation cost, respectively.

Table 5 - South Carolina Electric & Gas Company

Month	Invoice cost per Ton	Freight Cost per Ton	Total Cost per Ton	Cost per Mbtu	Btu of Coal
	$	$	$	$	Btu
Apr-04	37.53	13.40	50.93	2.0176	12,621
May-04	37.52	12.07	49.59	1.9566	12,672
Jun-04	39.53	12.92	52.45	2.0821	12,595
Jul-04	35.93	12.61	48.54	1.9187	12,649
Aug-04	41.14	11.26	52.40	2.0844	12,570
Sep-04	38.07	14.20	52.27	2.0901	12,504
Oct-04	37.82	13.17	50.99	2.0357	12,524
Nov-04	43.54	11.34	54.88	2.1668	12,664
Dec-04	37.47	12.94	50.41	2.0026	12,586
Jan-05	49.94	10.74	60.68	2.3853	12,720
Feb-05	43.17	15.49	58.66	2.3205	12,640
Mar-05	48.62	12.41	61.03	2.4081	12,672
Apr-05	47.06	13.81	60.87	2.4112	12,622
May-05	44.95	13.85	58.80	2.3278	12,630
Jun-05	46.56	15.36	61.92	2.4429	12,673
Average	**41.92**	**13.04**	**54.96**	**2.1767**	**12,623**

Table 6 - Duke Power Company

Month	Invoice Cost per Ton	Freight Cost per Ton	Total Cost per Ton	Cost per Mbtu	Btu of Coal
	$	$	$	$	Btu
Apr-04	32.18	15.41	47.59	1.9331	12,309
May-04	32.46	15.55	48.01	1.9591	12,253
Jun-04	32.05	16.54	48.59	1.9922	12,195
Jul-04	33.40	16.80	50.20	2.0517	12,234
Aug-04	34.25	16.52	50.77	2.0639	12,300
Sep-04	33.74	16.76	50.50	2.0631	12,239
Oct-04	32.17	16.54	48.71	1.9980	12,190
Nov-04	35.08	14.56	49.64	2.0264	12,248
Dec-04	33.79	17.42	51.21	2.1058	12,159
Jan-05	35.89	16.92	52.81	2.1615	12,216
Feb-05	37.66	16.29	53.95	2.1993	12,265
Mar-05	37.21	17.98	55.19	2.2537	12,244
Apr-05	37.29	18.69	55.98	2.2454	12,466
May-05	37.80	17.63	55.43	2.2832	12,138
Jun-05	40.33	18.62	58.95	2.3457	12,566
Average	**35.02**	**16.82**	**51.84**	**2.1121**	**12,268**

Table 7 - Progress Energy Carolinas, Inc.

Month	Invoice Cost per Ton	Freight Cost per Ton	Total Cost per Ton	Cost per Mbtu	Btu of Coal
	$	$	$	$	Btu
Apr-04	36.42	14.61	51.03	2.0560	12,410
May-04	35.64	15.04	50.68	2.0446	12,394
Jun-04	38.54	14.54	53.08	2.1495	12,347
Jul-04	44.20	13.78	57.98	2.3376	12,402
Aug-04	43.73	13.92	57.65	2.3394	12,322
Sep-04	41.06	14.03	55.09	2.2249	12,380
Oct-04	38.67	15.17	53.84	2.1706	12,402
Nov-04	41.14	14.84	55.98	2.2514	12,432
Dec-04	46.81	18.15	64.96	2.6387	12,309
Jan-05	44.38	18.58	62.96	2.5318	12,434
Feb-05	44.43	18.30	62.73	2.5100	12,496
Mar-05	47.05	17.69	64.74	2.5980	12,460
Apr-05	48.03	19.16	67.19	2.6927	12,476
May-05	47.41	19.65	67.06	2.7308	12,278
Jun-05	49.55	21.50	71.05	2.8719	12,370
Average	**43.14**	**16.60**	**59.73**	**2.4099**	**12,394**

It is important to compare the relative average cost per ton of delivered coal by utility. They are $54.96/ton, $51.84/ton, and $59.73/ton for the Company, Duke Power, and Progress Energy Carolinas, respectively (See Table 5, 6, and 7, above). Most noteworthy, the Company's overall average cost of delivered coal is in relatively close tolerance to the other two utilities. The tables also show that the Company purchased higher quality coal with an average Btu content greater than its minimum specification of 12,500 Btu. Duke Power and Progress Energy Carolinas purchased lesser quality coal with an average Btu content below 12,500 Btu.

To compare the major investor owned utilities, ORS performed a historical review of coal costs by reviewing producer cost, freight cost, and delivered cost. Graph 2 of Attachment F shows a close correlation between the major utilities with regard to producer cost. This graph demonstrates that there has been a similar market for coal available to each utility over the past several years. That is, no utility appears to have a relative advantage on producer cost for coal.

Graph 3 of Attachment G shows Duke Power and Progress Energy Carolinas have very similar historical freight costs. Due to expiring contracts and contentious contract re-negotiations with

NS railroad, Graph 3 also shows that Duke Power and Progress Energy Carolinas experienced a significant increase in freight cost in the first quarter of 2002. Consequently, since 2002, the Company has had an overall advantage on freight costs.

Graph 4 of Attachment H shows a close correlation of the major utilities with regard to the delivered cost of coal. Graph 5 of Attachment I shows the relative comparison of the quality of coal purchased by each major utility. As mentioned above, the Company has consistently purchased coal with a higher Btu content. With reference to Graph 2, it can be inferred that the Company has been successful in purchasing higher quality coal from the producers at similar costs paid by the other two major utilities for coal of a lesser quality.

In summary, during the review period, the Company maintained a market advantage on transportation and purchase price for higher quality coal. The Company successfully limited its expenditures securing coal from other transportation methods given the tardy and/or non-performance of CSX. Due to what appears to ORS to be a large number of tardy or non-deliveries by CSX, the Company should evaluate and explore all available and applicable legal remedies against CSX for failure to perform and determine the reasonableness of pursuing such remedies. In addition, the Company should have its contracts with CSX and NS structured to encourage timely delivery and should pursue the appropriate remedies when the contract terms are not met. Lastly, the Company should also evaluate alternate means of transportation to ensure adequate supply, inventory, and delivery diversity.

Fuel Mix

Table 8, below, demonstrates the effect on a utility's overall fuel expense due *solely* to generation mix from the rate base plants of each utility. Table 8 utilizes the percentage generation by fuel source for SCE&G, Duke Power Company and Progress Energy Carolinas (PEC) for the twelve months ended June 30, 2005, along with a predetermined cost per kilowatt-hour for each type of fuel source regardless of company plant affiliation. The fuel categories and associated costs used are Nuclear (0.5 cents/kwh), Coal (2.5 cents/kwh), Natural Gas/Oil (6.5 cents/kwh), and Hydro (0.0 cents/kwh). The predetermined costs are approximations for these fuel cost categories utilizing recent costs, representative of these three utilities. The total or overall cost for each utility is weighted for each fuel source by multiplying each fuel category cost by the percentage of generation produced from that fuel source. The individual weighted costs are then combined to show the resulting overall average fuel expense that would be expected for a company with that corresponding generation mix. Hydro generation is included at zero fuel cost to account for not only run-of-river type production with zero actual fuel costs, but also to weight the overall generation from pumped storage facilities where the pump-up costs are reflected in other type generation fuel costs. It should be noted that another factor, purchased power, has the potential to significantly affect fuel expenses also.

The intent of Table 8 is to show how rate based generating facilities impact fuel costs, and although purchased power is an important element of cost, it is generally more diverse and less predictable than these other cost categories. In addition, the companies' rate based plants have gone through certification processes as well as prudency reviews, and each utility's facilities have been formally determined to be appropriate for each respective system.

Table 8 - Projected Fuel Cost Based on Generation Mix by Fuel Type

Year Ended June 30, 2005

	SCE&G	(¢/kwh)	DUKE	(¢/kwh)	PEC	(¢/kwh)
Nuclear (0.5 ¢/kwh)	19.4%	0.10	47.3%	0.24	44.8%	0.22
Coal (2.5 ¢/kwh)	69.5%	1.74	51.1%	1.28	49.9%	1.25
Natural Gas/Oil (6.5 ¢/kwh)	6.4%	0.42	0.0%	0.00	3.7%	0.24
Hydro (0.0 ¢/kwh)	4.7%	0.00	1.6%	0.00	1.6%	0.00
Total (%)	100.0%		100.0%		100.0%	
Total (¢/kwh)		2.25		1.51		1.71

Setting identical predetermined costs for all three utilities equates to the assumption that each utility's fuel purchase costs are the same. The resulting diverse total costs for the three utilities demonstrates the significant effect that generation mix *alone* has on a utility's bottom line fuel expenses. The difference between the lowest (1.51 cents/kwh for Duke) and highest (2.25 cents/kwh for SCE&G) total fuel costs is approximately fifty (50%) percent.

Even with the assumption for all three utilities that all plant operations and fuel costs are reasonable, Table 8 demonstrates that there are logical and legitimate reasons and circumstances for one utility's costs exceeding those of another based *solely* on fuel mix diversity. Table 8 can be a useful tool in analyzing and explaining the varying fuel expenses among utilities in a more simplistic manner considering the complexity of the fuel procurement process and the operations of diverse generation facilities and systems.

Purchased Power and Off-system Sales

The Company currently has not entered into any long-term contracts for purchased power. The Company reports to ORS it is not opposed to securing long-term contracts but currently has sufficient capacity to satisfy its base load system requirements. However, the Company periodically supplements its available capacity with spot purchases to aid in meeting system peaking needs.

The Company maintains a comprehensive computerized tracking system to ensure it assigns proper economic order to its generation and purchased power. The tracking system produces a summary detailing hour-by-hour purchases for each megawatt-hr of power on the system. Using the dispatch data sheets for generation and purchased power, an "after the fact" analysis is performed daily to identify the least cost method for power production. An avoided cost comparison of cost margins for self-generation and purchased power is also performed. Costs are first assigned by allocating the least cost to the native load of the system. Next, cost assignments are allotted similarly based on a hierarchical cost structure. Specifically, the cost allocation from lowest to highest is as follows: Native load, Fairfield pump/storage pumping, long-term contract sales, Company prescheduled off-system sales, 3rd Party prescheduled off-system sales, Company hourly off-system sales, and 3rd Party hourly sales.

The Company is adhering to its internal practices to ensure the least cost energy is dedicated to the retail native load. This approach of cost allocation directly benefits the retail rate payers.

Affiliate Transactions

Synthetic Fuel

The Company partners in SC CoalTech #1 and CoalTech #1 for the production of synthetic fuel at its Wateree and Canadys power stations, respectively. The Company has a 40% ownership in SC CoalTech #1, and a 25% ownership in CoalTech #1. The affiliate transaction at the Company's Wateree plant entails three major steps: (1) the Company sells coal to SC CoalTech #1; (2) SC CoalTech #1 uses this coal to produce the synthetic fuel; and (3) the Company purchases this coal, now a synthetic fuel, from SC CoalTech #1 at a $[redacted]/ton discount from the original selling price. The Company engages in a similar affiliate transaction with CoalTech #1 at its Canadys plant. These transactions afford the Company a net discount by purchasing synthetic fuel from its affiliate. The synfuel process is discussed in more details in the Fuel Procurement Section, above.

Natural Gas

The Company's Jasper generating plant is contracted with SCANA Energy Marketing Inc. (SEMI), a non-regulated subsidiary of SCANA Corporation established to market natural gas and other hydrocarbon products, for both its Interstate capacity and supply needs. The Jasper plant's fuel line connects to SCG Pipeline, a wholly owned subsidiary of SCANA Corp., formed primarily to build interstate natural gas pipelines. SEMI has a contract with Southern Natural Gas Company for interstate pipeline transportation capacity. SEMI also has a contract with SCG Pipeline, Inc. for interstate pipeline transportation capacity to support the Jasper contract with the Company.

SEMI serves the Jasper plant via SCG Pipeline and is able to utilize its dual rights on SCG Pipeline and Southern Natural to assure dependable supply to the Jasper facility (i.e., gas from Elba and gas from the Gulf). SEMI manages all of Jasper's gas needs.

SEMI has a contract with British Gas for natural gas commodity from Elba Island LNG terminal. SEMI in turn has a contract with the Company to provide gas service to the Jasper plant: 120,000 dt/day for Jasper's use for 15 years.

The Company's Urquhart power plant is located on a lateral pipeline owned by its electric division that connects to Southern Natural Gas Company's pipeline near Aiken, SC. The Company contracts for the interstate pipeline capacity on Southern Natural to serve Urquhart. The Company also contracts with various producers for the natural gas supply to serve Urquhart. These natural gas producers are not affiliated with SCANA Corporation or any of its subsidiaries. The lateral pipeline that connects Southern Natural to Urquhart was previously owned by South Carolina Pipeline Corporation (SCPC), also a wholly owned subsidiary of SCANA Corporation, focused on providing natural gas to South Carolina customers. The lateral pipeline was transferred from SCPC to the Company in early 2005.

SCANA Services Inc., which provides administrative, management and other services to the subsidiaries and business units within SCANA Corporation, is utilized by the Company to arrange gas supply (with gas producers) and transportation (with interstate pipelines) for its gas fired generation facilities. SCANA Services takes action at the request of the Company's generation division.

Coal Hedging Activities

The Company currently does not employ any financial hedging activities for coal purchases. The Company's internal procedures and practices satisfactorily minimize the Company's risk and provide adequate control. However, the Company should continue to evaluate possible advantageous hedging opportunities to mitigate market volatility.

Inventory Management

ORS reviewed the Company's inventory control process (See Attachment J). The Company monitors its coal inventory on a system wide basis to include Williams Station (GENCO). In accordance with the Company's Fossil Fuel Management Policy, the Company's annual average target for coal inventory is 925,000 tons. A review of the Company's 2005 inventory revealed the Company to have an average annual inventory of 841,082 tons (Note: September through December are forecasted numbers). This represents a 9.07% shortfall of the Company's target. This shortfall is related to the delivery difficulties the Company experienced in 2005. (See the Transportation of Fuel Section for more details on the performance of the CSX railroad.) Similarly, a review of the Company's 2006 inventory forecast revealed that the Company anticipates having an average annual inventory of 892,890 tons. This represents a 3.47% shortfall of the Company's target. The shortfall of 3.47% or approximately 32,000 tons is considered small and not significant.

The Company should continue to work toward rebuilding depleted inventories realized in 2005 and achieving its target in 2006.

Generation Planning

ORS reviewed the Company's 2005 Integrated Resource Plan (IRP). The IRP is detailed and comprehensive. It provides a thorough evaluation of the Company's future generation needs, demand-side management practices, and supply-side management practice for the next 15 years, or through 2019.

The Company's load forecast is based on an anticipated average annual growth rate of 2.2%. The summer peak demand and the winter peak demand are expected to increase at an annual rate of 2.2% and 2.3%, respectively. This growth rate also reflects a summer peak load and a winter peak load of 6,327 MW and 5,847 MW, respectively. The current 2005 summer peak and winter peak loads are 4,641 MW and 4,240 MW, respectively. This represents an increase of 36% in the summer peak load and 38% in the winter peak load over the 15 year period. These increases correspond to total energy sales of 31,624 GWH in 2019.

The Company's demand-side management program consists of customer information programs, energy conservation, and load management programs. The load management program secures 239 MW of interruptible load and 23 MW of standby generators. This provides a total of 262 MW of available additional capacity if needed.

The Company's supply-side management program currently maintains 5,834 MW of available capacity. The capacity is distributed through a diverse mix of generating units. The units are 45% coal, 11% nuclear, 30% natural gas, and 14% hydro. The supply-side management program incorporates a 12%-18% reserve margin. These reserves provide for VACAR Operating reserves, supply-side risk mitigation, and demand-side risk mitigation. The Company's IRP shows a need for additional capacity of approximately 100 MW by 2009.
The Company's IRP is reasonable and satisfactorily forecasts future system needs. The Company's IRP should additionally evaluate and categorize the type of generation (i.e., baseload, intermediate, or peaking) necessary to satisfy the Company's future capacity needs.

ORS Site Visits

ORS met formally and informally on numerous occasions to discuss the Company's fuel procurement practices. These meetings occurred primarily at the ORS headquarters. However, ORS met periodically at the Company's headquarters as well as its remote offices. ORS visited the Company's Cope power plant to physically observe the electricity generation process at a fossil fuel plant. Also, ORS visited the Company's purchase power operations and the Company's unit dispatching operations.

ORS also toured the mining operations and coal loading system (tipple) of one of the Company's major coal suppliers, TECO, in Pikeville and Hazard, Kentucky. ORS toured TECO's surface and underground mining activities as well as its coal laboratories dedicated to sampling and determining coal qualities.

Recommendations

ORS offers the following suggestions and/or recommendations to enhance the Company's fuel management activities:

I. The Company should only consider purchasing coal from expensive domestic or off-shore markets as a last alternative in acquiring fuel.

II. The Company should evaluate and take advantage of alternative fuels as they become practical.

III. The Company should monitor new technology and its potential benefits as technology evolves. In particular, the Company should investigate the feasibility of on-site coal/petroleum coke gasification.

IV. The Company should closely evaluate the potential of blending coal on-site at its power stations.

V. The Company should evaluate and explore all available and applicable legal remedies against CSX for failure to perform and determine the reasonableness of pursuing such remedies.

VI. The Company should evaluate alternate means of transportation to ensure adequate supply, inventory, and delivery diversity.

VII. The Company should evaluate possible advantageous hedging opportunities to mitigate market volatility.

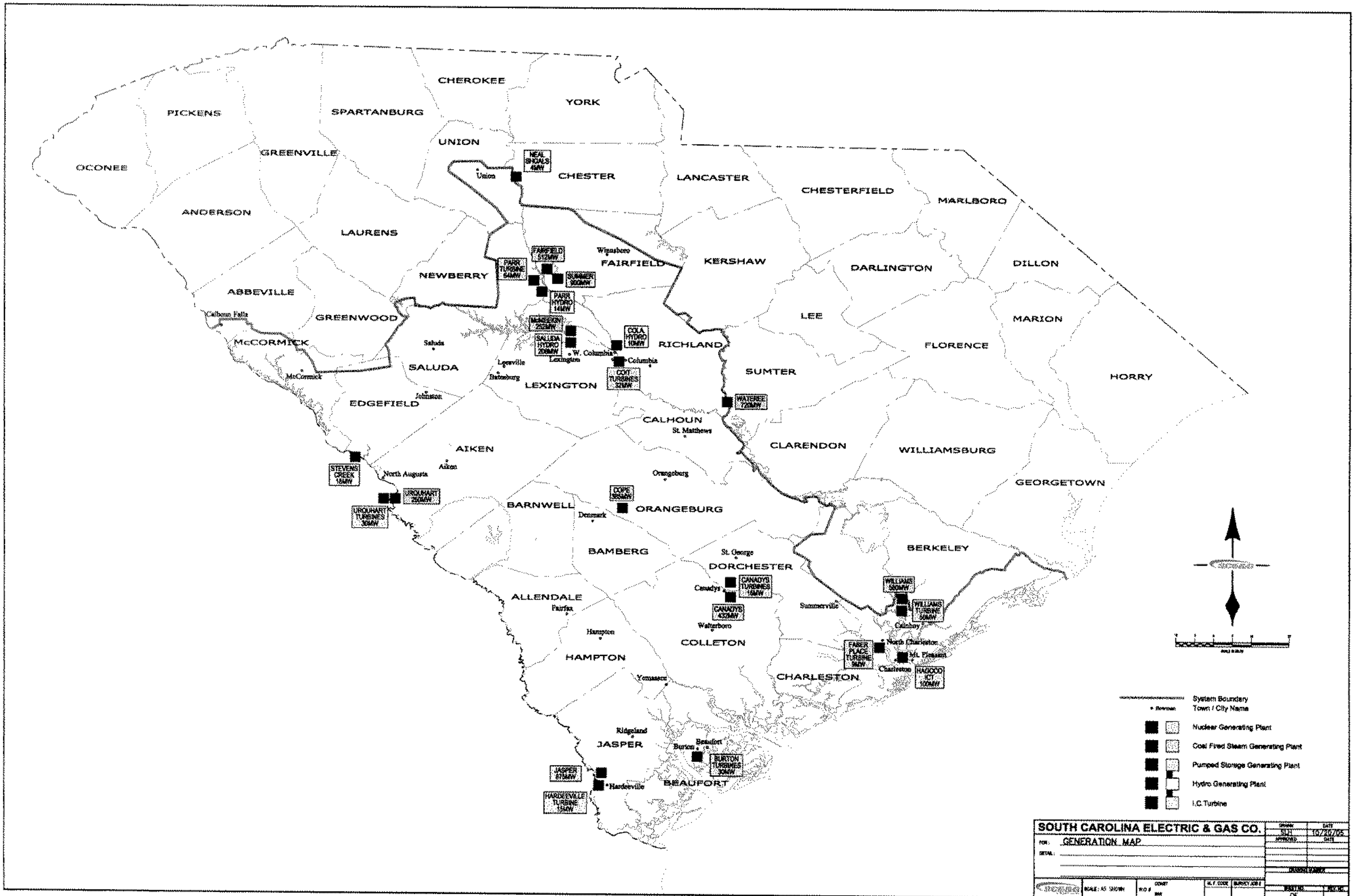
VIII. The Company should work toward rebuilding depleted inventories realized in 2005 and achieving its target in 2006.

IX. The Company should evaluate and categorize the type of generation (i.e., baseload, intermediate, or peaking) necessary to satisfy its future capacity needs.

X. In addition to reports currently filed with ORS in accordance with state statute and/or Commission Order, ORS requests the following information:

- Annual updated fuel forecast
- Monthly Over/Under Cumulative Recovery Report
- Notice of significant cumulative recovery trends
- Notice of significant fuel cost trends
- Monthly FERC Form 423
- Any industry solicitation for coal

ATTACHMENT A



OCONEE
PICKENS
GREENVILLE
SPARTANBURG
CHEROKEE
YORK
UNION
CHESTER
LANCASTER
CHESTERFIELD
MARLBORO
ANDERSON
LAURENS
NEWBERRY
FAIRFIELD
KERSHAW
DARLINGTON
DILLON
ABBEVILLE
GREENWOOD
McCORMICK
LEE
MARION
SALUDA
LEXINGTON
RICHLAND
SUMTER
FLORENCE
HORRY
EDGEFIELD
CALHOUN
AIKEN
CLARENDON
WILLIAMSBURG
GEORGETOWN
BARNWELL
ORANGEBURG
BAMBERG
DORCHESTER
BERKELEY
ALLENDALE
COLLETON
HAMPTON
CHARLESTON
JASPER
BEAUFORT
Union
Winnsboro
Calhoun Falls
McCormick
Saluda
Leesville
Batesburg
Lexington
W. Columbia
Columbia
Johnston
St. Matthews
North Augusta
Aiken
Orangeburg
Denmark
St. George
Canadys
Walterboro
Summerville
Cainhoy
North Charleston
Mt. Pleasant
Charleston
Fairfax
Hampton
Yemassee
Ridgeland
Beaufort
Burton
Hardeeville
NEAL SHOALS
FAIRFIELD
PARR TURBINE 64MW
SUMMER
PARR HYDRO 14MW
SALUDA HYDRO 206MW
COLA HYDRO 10MW
COIT TURBINES 32MW
WATEREE
STEVENS CREEK
URQUHART
URQUHART TURBINES
COPE
CANADYS TURBINES
CANADYS 432MW
WILLIAMS
WILLIAMS TURBINE
FABER PLACE TURBINE
HAGOOD ICT 100MW
BURTON TURBINES
JASPER
HARDEEVILLE TURBINE
System Boundary
Town / City Name
Nuclear Generating Plant
Coal Fired Steam Generating Plant
Pumped Storage Generating Plant
Hydro Generating Plant
I.C.Turbine
SOUTH CAROLINA ELECTRIC & GAS CO.
FOR: GENERATION MAP
DETAIL:
SCALE: AS SHOWN
10/20/05

ATTACHMENT B

SC ELECTRIC AND GAS COMPANY FUEL STUDY

PRODUCER LONG-TERM CONTRACTS (1-YEAR AND GREATER)

REDACTED

ATTACHMENT C

SC ELECTRIC AND GAS COMPANY FUEL STUDY
PRODUCER SPOT CONTRACTS (LESS THAN 1 YEAR)

REDACTED

ATTACHMENT D

Fossil Fuel Management Policy for Coal Procurement Outline

Fossil Fuel Management

- Mission
- Objectives
- Program Activities
- Procurement Policies
- Fossil Fuel Policy Group
- Fossil Fuel Supply Department Organization

Planning

- Short-Term Planning
- Long-Term Planning

Procurement

- Bidders List
- Mining Facilities
- Bidding Process
- Evaluation & Selection
- Recommendations/Approvals
- Contract Pricing Mechanisms

Administration

- Coal Receipts and Quality
- Inventory Management

Auditing

Transportation

- Planning
- Administration

Fossil Fuel By-Products Management

ATTACHMENT E

Tampa Electric Integrated Gasification Combined-Cycle Project

Project Completed

Participant

Tampa Electric Company

Additional Team Members

Texaco Development Corporation—gasification technology supplier

General Electric Corporation—combined-cycle technology supplier

Air Products and Chemicals, Inc.—air separation unit supplier

Monsanto Enviro-Chem Systems, Inc.—sulfuric acid plant supplier

TECO Power Services Corporation—project manager and marketer

Bechtel Power Corporation—architect and engineer

Location

Mulberry, Polk County, FL (Tampa Electric Company's Polk Power Station (PPS), Unit No. 1)

Technology

Advanced integrated gasification combined-cycle (IGCC) system using Texaco's pressurized, entrained-flow, oxygen-blown gasifier technology

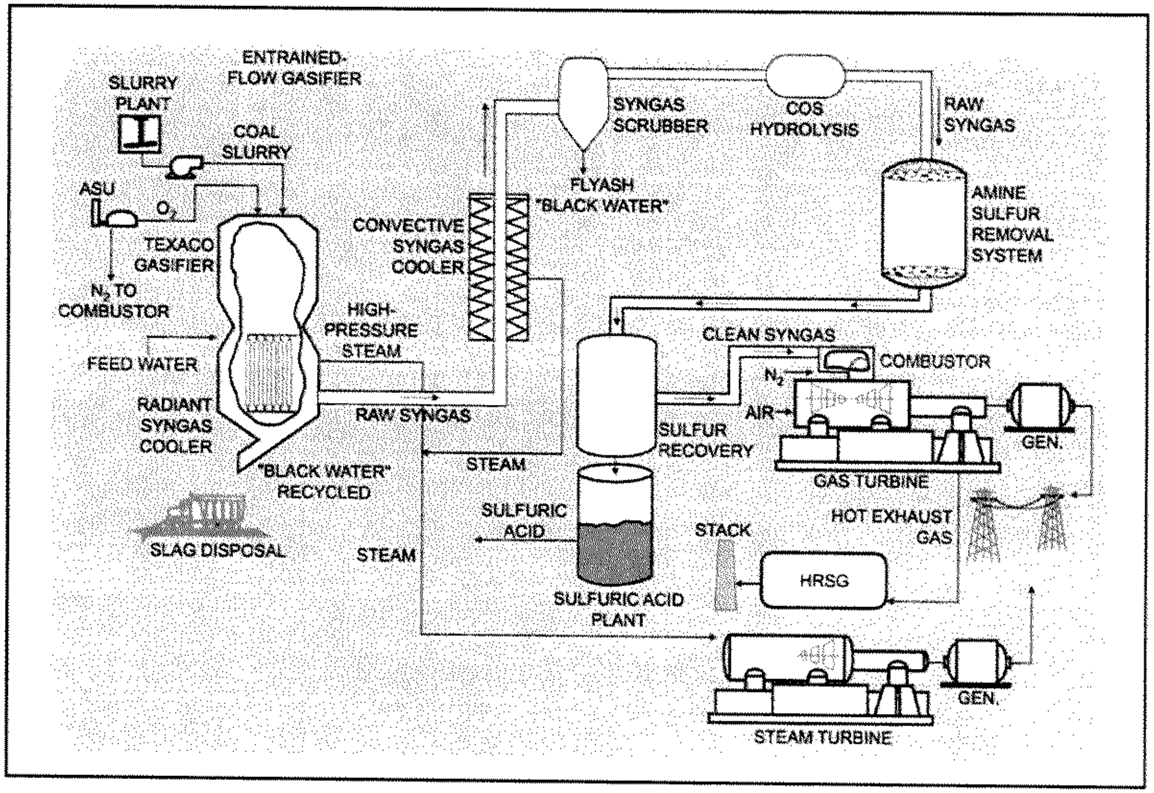
Plant Capacity/Production

315 MWe (gross), 250 MWe (net)

Coal

Illinois #5 & #6, Pittsburgh #8, West Kentucky #11, and Kentucky #9, Indiana #5 & #6 (2.5–3.5% sulfur); petcoke; petcoke/coal blends; and biomass

*Additional project cost overruns were funded 100% by the participant for a final total project funding of $606,916,000.



Project Funding

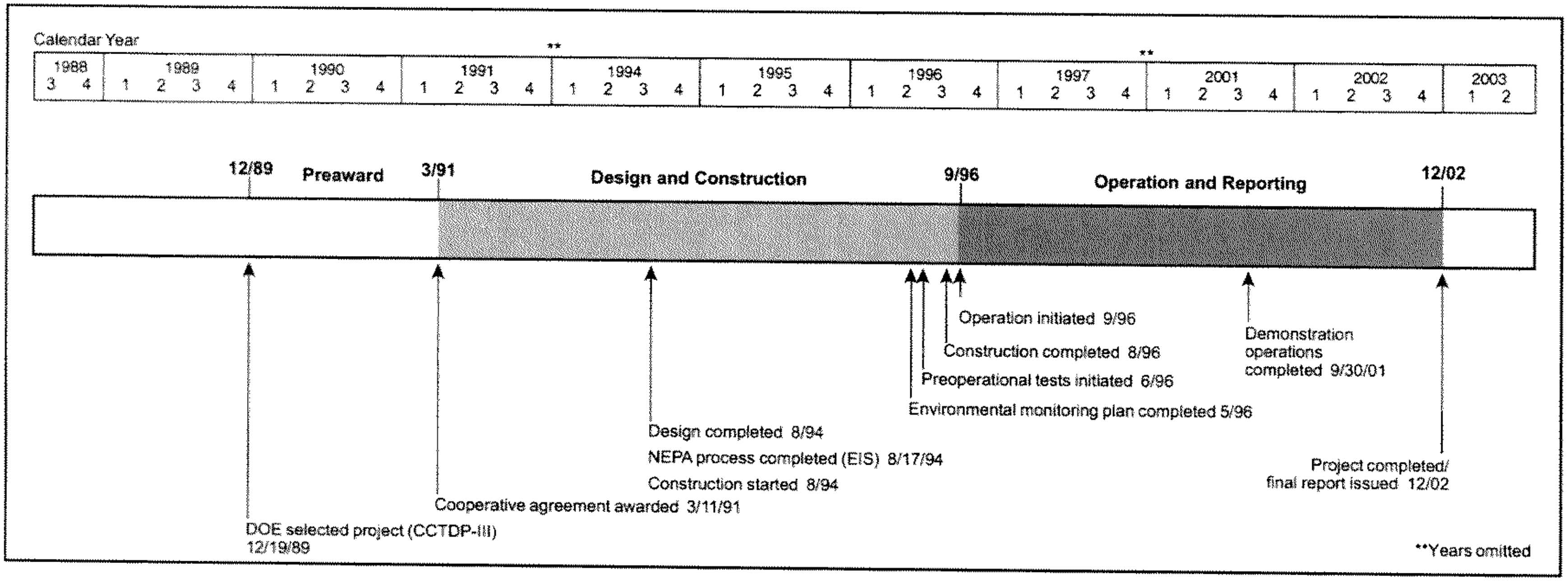
Total*	$303,288,446	100%
DOE	150,894,223	49
Participant	152,394,223	51

Project Objective

To demonstrate IGCC technology in a greenfield commercial electric utility application at the 250-MWe size using a pressurized, entrained-flow, oxygen-blown gasifier with full heat recovery, conventional cold-gas cleanup, and an advanced gas turbine with nitrogen injection for power augmentation and NO_x control.

Technology/Project Description

Coal/water slurry and oxygen are reacted at high temperature and pressure to produce approximately 245 Btu/SCF syngas (LHV) in a Texaco gasifier. Molten ash flows out of the bottom of the gasifier into a water-filled sump where it forms a solid slag. The syngas moves from the gasifier to a radiant syngas cooler and a convective syngas cooler (CSC), which cool the syngas while generating high-pressure steam. The cooled gases flow to a water-wash syngas scrubber for particulate removal. Next, a hydrolysis reactor converts carbonyl sulfide (COS) in the raw syngas to hydrogen sulfide (H_2S) that is more easily removed. The raw syngas is then further cooled before entering a conventional amine sulfur removal system and sulfuric acid plant (SAP). The cleaned gases are then reheated and routed to a combined-cycle system for power generation. A GE MS 7001FA gas turbine generates 192 MWe. Thermal NO_x is controlled to 0.7 lb/MWh by injecting nitrogen. A steam turbine uses steam produced by cooling the syngas and superheated with the gas turbine exhaust gases in the HRSG to produce an additional 123 MWe. The air separation unit consumes 55 MW and auxiliaries require 10 MW, resulting in 250 MWe net power to the grid. The plant heat rate is 9,650 Btu/kWh (HHV).



Results Summary

Environmental Performance

- The PPS IGCC removed over 97% of feedstock sulfur when operated on low-cost, high-sulfur coal, petcoke, and coal/petcoke blends.
- Typical NO_x emissions were 0.7 lb/MWh, which were below the permitted limit of 0.9 lb/MWh and far below New Source Performance Standard (NSPS) NO_x levels of 1.6 lb/MWh for electric utility units.
- The PM emissions were typically less than 0.04 lb/ MWh, which is about 5% of those from conventional coal-fired plants equipped with electrostatic precipitation.
- The CO emissions were permitted at 99 lb/hr and averaged 7.2 lb/hr; volatile organic compound (VOC) emissions were negligible; and mercury emissions (on coal) without controls were half the potential release based on mercury levels in the coal.

Operational Performance

- The PPS combustion turbine logged 34,800 hours over the 5-year demonstration, of which 28,500 hours were syngas-fired; syngas firing produced over 8.6 million MWh of electricity.
- The gasifier on-stream factor steadily increased, reaching 70–80% after 2½ years; overall PPS availability, with distillate fuel as backup, averaged 90% after 1½ years.
- Carbon conversion was lower than expected—in the low to mid 90% range versus the expected 97.5–98%. This rendered the ASU design capacity inadequate because of a need to recycle flyash, lowering PPS output to 235 MWe net, and required doubling the capacity of the solids handling system.
- Refractory liner life was problematic during the demonstration largely due to frequent fuel changes and attendant undesirable fluctuations in operating conditions, but a coal/petcoke blend was identified to eliminate the problem in commercial service.
- In the high-temperature heat recovery systems downstream of the gasifier, the radiant syngas cooler seals underwent design changes or corrections for fabrication defects; convective syngas coolers required geometric improvements to reduce plugging; and raw gas/clean gas heat exchangers required removal due to stress corrosion.
- A COS hydrolysis unit had to be added to meet sulfur-reduction targets and an ion exchange unit added to prevent buildup of heat-stable salts in the MDEA unit.
- "Y" strainers and a 10 micron filter system proved critical to turbine protection from pipe-scale during start-ups.

Economic Performance

- A capital cost of $1,650/kW (2001$) was estimated for a new 250 MWe (net) IGCC plant based on the PPS configuration incorporating lessons learned. A capital cost of $1,300/kW (2001$) was estimated for a new plant that allowed for benefits derived from economies of scale, technology improvements, and replication of proven configurations to eliminate costly reinvention.

Project Summary

Tampa Electric worked with the local community, state organizations, and environmental groups to make the project an environmental showcase; and engaged DOE and the technical community to move IGCC closer to mainstream market acceptance. Both of these goals were met.

This project has been the recipient of numerous environmental and technological achievement awards. These include the Ecological Society of America Corporate Award, the Florida Audubon Society Corporate Award, and *Power* magazine's 1997 Power Plant of the Year Award. The plant was inducted into *Power* magazine's Power Plant Hall of Fame.

Over the 5-year demonstration period, Tampa Electric carried out a systematic campaign to address and resolve the usual technical issues accompanying first-of-a-kind plants. Tampa Electric showed through the demonstration that a modest-sized utility, with expertise in coal-fired generation, can build and operate an IGCC plant.

Environmental Performance

The PPS IGCC removed over 97% of the feedstock sulfur when operated on low-cost, high-sulfur coals, petcoke, and blends. A material balance on a 3.0% sulfur coal showed that 7.0% of the sulfur is locked up in the inert slag leaving the gasifier. The MDEA acid gas system removed 97.5% of the H_2S from the raw syngas. The COS hydrolysis to H_2S proved critical to maintaining high sulfur capture efficiency because 5% of the sulfur in coal feedstocks was converted to COS (twice the amount expected) and the MDEA system was not effective in removing COS. The SAP recovered 99.7% of the sulfur it was fed.

Permit limits on NO_x emissions during the PPS demonstration period were 25 parts per million by volume on a dry basis (ppmvd) corrected to 15% O_2. This value equated to 35 parts per million (ppm) as measured at the stack by a continuous emissions monitor (CEM). The permit limit is also equivalent to about 220 lb/hr NO_x or 0.9 lb/MWh. Typical Polk IGCC NO_x emissions were about 0.7 lb/MWh, or below 30 ppm by CEM. These emission rates are a fraction of those from conventional coal-fired power plants equipped with low-NO_x combustion systems. For comparison, the NSPS for electric utility units is 1.6 lb/MWh, regardless of fuel type.

The PM emissions from the IGCC are typically less than 0.04 lb/MWh, which is approximately 5% of those from conventional coal-fired plants equipped with electrostatic precipitators. These near-zero emissions are the result of the concentrated, low-volume raw syngas flow and application of intensive liquid scrubbing and no less than 15 stages of liquid-gas contact.

The CO emissions, permitted at 99 lb/hr, averaged 7.2 lb/hr. The VOC emissions, permitted at 3 lb/hr, averaged 0.02 lb/hr. Mercury emissions were not regulated, but measurements taken showed that the IGCC removed about half of the mercury constituent in coal feedstocks.

Operational Performance

Over the course of the demonstration, the PPS combustion turbine logged 34,800 hours of which 28,500 hours were syngas fired. The 28,500 hours of syngas firing produced over 8.6 million MWh of electricity. In producing the syngas, the gasifier typically consumed 2,500 tons of coal or coal/petcoke blends per day.

The gasifier and associated systems involved in producing clean syngas showed steady improvement in the unit's in-service (on-stream) factor over the first four years, reaching 70–80% after 2½ years, before suffering a setback in the fifth and final demonstration year. The fifth year was not considered representative. It included a lengthy planned outage to deal with gasifier refractory damage incurred by frequent feedstock changes, followed by a rare ASU forced outage and the one-time removal of sootblower lances. The on-stream factor is the percentage of time the gasifier and associated systems were in operation over the total number of hours in the year of operation. The availability of the combined-cycle power block to produce electricity from either syngas or distillate was approximately 90% over the last four years of the demonstration. Tampa Electric also calculated on-peak availability because of the importance of the plant in meeting peak summer demand. The peak availabilities for 2000 and 2001 were 94.9% and 97.7%, respectively.

The following is a summary of the highlights of the technical issues that emerged during the demonstration. Most of the issues were resolved, and others served as lessons learned to improve the technology for future plants. Together, the issues served to advance the technology closer to widespread commercial deployment.

Lower-than-anticipated carbon conversion in the gasifier had major cost and performance impacts that reverberated through the IGCC system. Carbon conversions of 97.5–98% per pass were expected based on performance of smaller Texaco gasifiers. The PPS gasifier achieved per pass carbon conversion in the low- to mid- 90% range.

Even at design capacity, the ASU could not deliver enough air to meet the total gasifier oxygen requirements given the unexpectedly low carbon conversion and the resulting need to recycle flyash (which reduced fuel quality). Moreover, Tampa Electric desired the flexibility to process low-quality fuels.

Essentially all carbon steel parts in contact with the slurry feedstock had to be replaced or coated with corrosion-resistant materials, and high-wear areas had to be hardened.

Tampa Electric evaluated numerous modifications to the slurry feed injectors in an attempt to resolve the carbon conversion issue. Only marginal improvement resulted.

A two-year gasifier refractory liner life commercial goal established for the PPS was not met during the demonstration period primarily because of frequent fuel changes. The fuel changes introduced risk in operational settings and less-than-optimal operating conditions as adjustments were made. Also, the high number of start-up and shutdown cycles experienced during the demonstration period accelerated refractory spalling.

Tampa Electric carried out extensive feedstock testing during the demonstration with refractory life being a prime consideration. Testing showed that a blend of 45% Black Beauty and Mina Norte coals with 55% petroleum coke provided excellent cost and performance characteristics and the potential for long refractory liner life.

Contributing to the refractory degradation was the inability to directly measure gasifier temperatures on a realtime basis. Thermocouples failed to survive the gasifier flow path. Gasifier temperature measurements primarily relied on "inferential measurement" based on methane formation. Monitoring and control of gasifier temperature also is critical for control of slag viscosity and flyash volume.

All radiant syngas cooler seals eventually failed due to either fabrication defects or design flaws, all of which were corrected. Corrections included removal of all but 8 of the 122 sootblower lances. Only four lances are used as sootblowers. The other four serve as purge points for injection of N_2 during start-up and shutdown.

The CSC fire-tube heat exchanger was a source of frequent plugging and forced outages through 1999. The plugging primarily occurred at the CSC tubesheet inlet. In 1999, significant geometric improvements dramatically reduced plugging by more than half. Although not eliminated, CSC pluggage is deemed manageable.

The gasifier's lower-than-expected carbon conversion required twice as much fly ash and associated black water to be processed as originally designed. This increased volume essentially overwhelmed the solids handling system, precluded slag sales, and posed significant disposal costs. To resolve these issues, Tampa Electric (1) doubled the capacity of the fines (predominately flyash) handling system; (2) provided the capability to recycle 100% of the settler bottoms flyash to the gasifier slurry preparation system; (3) used condensate water instead of grey water in the slag removal system and stripped the ammonia from that condensate water; and (4) added a drag conveyor and screen to de-water and separate the fly-ash from the slag. With these changes, operation on 100% coal enabled sales of the slag while recycling 100% of the settler bottom flyash and generating 235 MWe (net). Tampa Electric future plans include increasing ASU capacity to provide enough oxygen to compensate for added fuel required to boost output to the rated capacity of 250 MWe year round.

In the original IGCC design, heat exchangers were incorporated downstream of the CSC to recover process heat by warming clean gas and diluent N_2 going to the combustion turbine. Flyash deposits from the raw syngas resulted in stress corrosion, cracking of the tubes, and turbine blade damage. These heat exchangers were removed because the heat recovery, less than 1.7% of the fuel's heating value, did not warrant the cost of redesign.

Tampa Electric incorporated a COS hydrolysis system in August 1999. An ion exchange system was subsequently added to control a high rate of heat-stable salt formation resulting from COS hydrolysis.

The only major power block forced outages during syngas-based operation resulted from failures of the raw gas/clean gas heat exchanger (since removed) in the absence of protective "Y" strainers. The "Y" strainers had been removed for repair. "Y" strainers subsequently proved critical for start-ups because of the release of large volumes of pipe scale. To increase turbine protection and reduce "Y" strainer cleaning, a 10 micron final syngas filter was installed upstream of the syngas strainers. This filter was sized to catch a year's worth of pipe scale.

Economic Performance

Tampa Electric estimated a capital cost of $1,650/kW (2001$) for installing a new single-train 250-MWe unit at the Polk site, based on the PPS configuration and incorporating all lessons learned. This estimate reflected the cost of the plant as if it were instantaneously conceived, permitted, and erected (overnight cost) in mid-2001. The single-train PPS configuration contributed to the high cost in that no benefits accrued from economies of scale in using common balance-of-plant systems. Tampa Electric also noted a number of site-specific factors adding to high costs. Tampa Electric developed another capital cost estimate, that included moderated site-specific factors and allowed benefits from economies of scale, technical improvement, and replication of proven configurations to eliminate costly re-invention. Application of these benefits reduced the estimated capital cost to $1,300/kW (2001$).

Commercial Applications

During the course of the demonstration, Tampa Electric addressed the future of IGCC, reflecting on typical concerns expressed by visitors, numbering over 2,500 and representing 20 countries. In regard to cost, the primary concern, Tampa Electric pointed out that capital costs will be lower for next-generation IGCC, further IGCC demonstrations would accelerate cost reduction, and higher initial costs for IGCC can be offset by long-term fuel savings. As to the associated factor of economic risk, Tampa Electric observed that (1) assumption of overall plant performance risk by a single entity rather than separate entities for individual process units would reduce the difficulty in obtaining financing; (2) a return to steady economic growth in the United States would encourage potential IGCC users to take a longer-term investment view, and (3) a lasting change in the expected availability or price differential of natural gas to coal would tip the risk-versus-reward scale toward IGCC. Also, environmental legislation requiring mercury or CO_2 removal would provide an economic advantage to IGCC over conventional coal-fired power generation because these emissions are readily removed from concentrated IGCC gas streams.

As to availability, Tampa Electric noted that: (1) the PPS gasifier availability is lower than can be expected for subsequent IGCC plants incorporating lessons learned; (2) overall PPS availability, including operation on backup fuel, is very high; and (3) the PPS experience showed that availability can be effectively managed.

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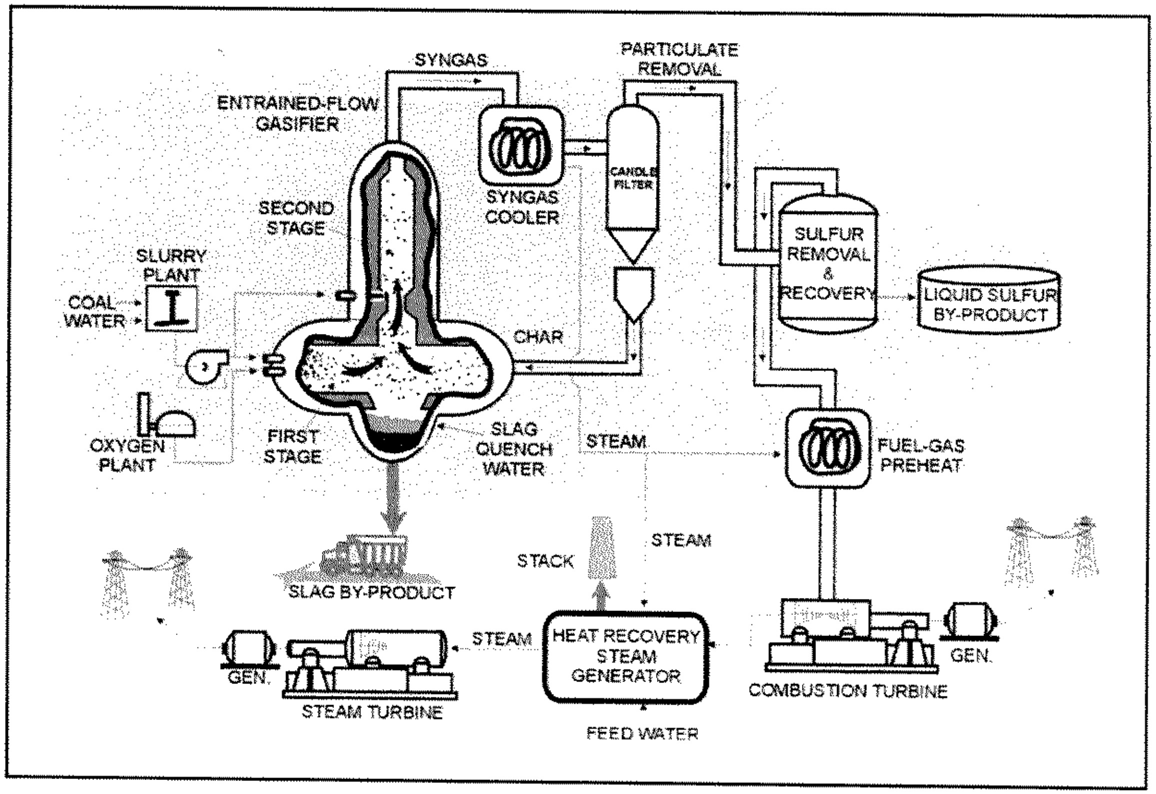
Tampa Electric Integrated Gasification Combined-Cycle Project—An Update. U.S. Department of Energy. July 2000.

Wabash River Coal Gasification Repowering Project



Project completed

Participant

Wabash River Coal Gasification Repowering Project Joint Venture (a joint venture of Dynegy and PSI Energy, Inc.)

Additional Team Members

PSI Energy, Inc.—host

Dynegy (formerly Destec Energy, Inc., a subsidiary of Natural Gas Clearinghouse)—engineer and gas plant operator

Location

West Terre Haute, Vigo County, IN (PSI Energy's Wabash River Generating Station, Unit No. 1)

Technology

Integrated gasification combined-cycle (IGCC) using Global Energy's two-stage pressurized, oxygen-blown, entrained-flow gasification system—E-Gas Technology™

Plant Capacity/Production

296 MWe (gross), 262 MWe (net)

Coal

Illinois Basin bituminous (Petroleum coke also used)

Project Funding

Total	$438,200,000	100%
DOE	219,100,000	50
Participant	219,100,000	50

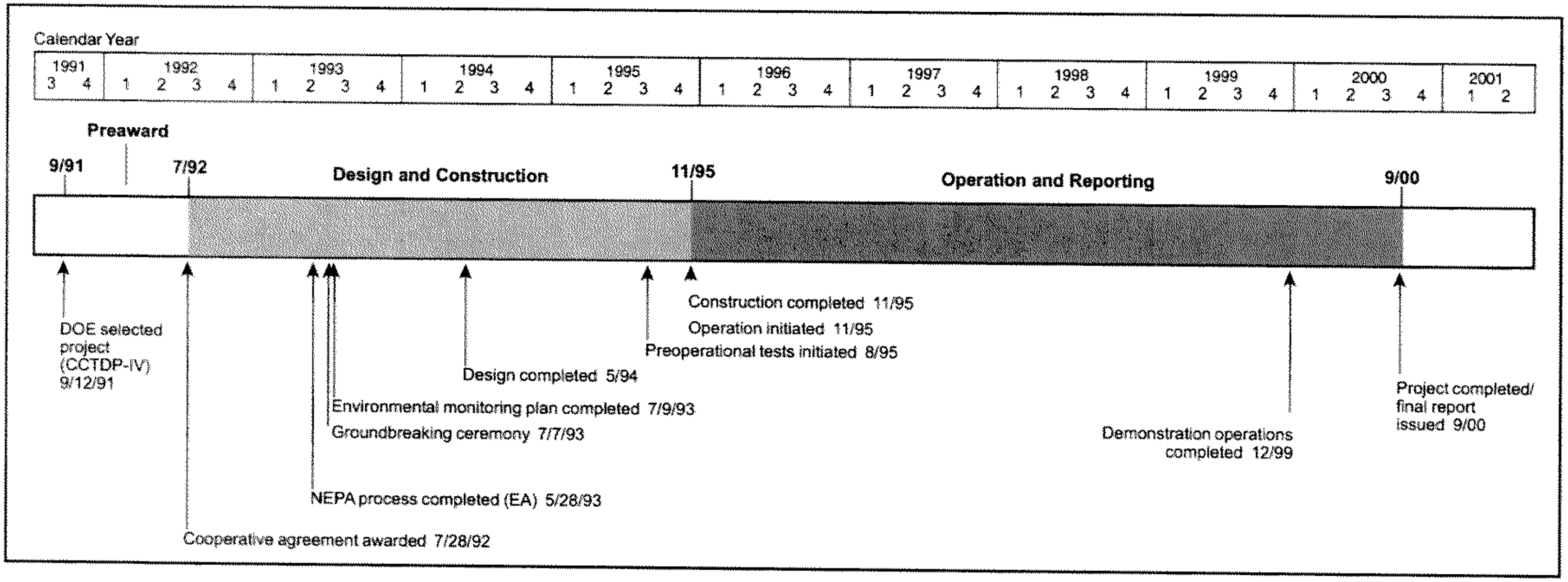
Project Objective

To demonstrate utility repowering with a two-stage, pressurized, oxygen-blown, entrained-flow IGCC system, including advancements in the technology relevant to the use of high-sulfur bituminous coal; and to assess long-term reliability, availability, and maintainability of the system at a fully commercial scale.

Technology/Project Description

The Destec, now E-Gas Technology™, process features an oxygen-blown, continuous-slagging, two-stage, entrained flow gasifier. Coal is slurried, combined with 95% pure oxygen, and injected into the first stage of the gasifier, which operates at 2,600 °F/400 psig. In the first stage, the coal slurry undergoes a partial oxidation reaction at temperatures high enough to bring the coal's ash above its melting point. The fluid ash falls through a tap hole at the bottom of the first stage into a water quench, forming an inert vitreous slag. The syngas flows to the second stage, where additional coal slurry is injected. This coal is pyrolyzed in an endothermic reaction with the hot syngas to enhance syngas heating value and improve efficiency.

The syngas then flows to the syngas cooler, essentially a fire tube steam generator, to produce high-pressure saturated steam. After cooling in the syngas cooler, particulates are removed in a hot/dry filter and recycled to the gasifier. The syngas is further cooled in a series of heat exchangers. The syngas is water-scrubbed to remove chlorides and passed through a catalyst that hydrolyzes carbonyl sulfide into hydrogen sulfide. Hydrogen sulfide is removed in the acid gas removal system using MDEA-based absorber/stripper columns. A Claus unit is used to produce elemental sulfur as a salable by-product. The "sweet" gas is then moisturized, preheated, and piped to the power block. The power block consists of a single 192-MWe General Electric MS 7001FA (Frame 7 FA) gas turbine, a Foster Wheeler single-drum heat recovery steam generator with reheat, and a 1952-vintage Westinghouse reheat steam turbine.



Results Summary

Environmental

- The SO_2 capture efficiency was greater than 99%, keeping SO_2 emissions consistently below 0.1 lb/10^6 Btu and reaching as low as 0.03 lb/10^6 Btu. Sulfur-based pollutants were transformed into 99.99% pure sulfur, a highly valued by-product—33,388 tons produced during the demonstration period.
- The NO_x emissions were 0.15 lb/10^6 Btu, which meets the 2003 target emission limits for ozone non-attainment areas, or 1.09 lb/MWh, and exceeds performance requirement based on the New Source Performance Standard of 1.6 lb/MWh.
- Particulate emissions were below detectable limits.
- Carbon monoxide emissions, averaging 0.05 lb/10^6 Btu, were well within industry standards.
- Coal ash was converted to a low-carbon vitreous slag, impervious to leaching and valued as an aggregate in construction or as grit for abrasives and roofing materials; and trace metals from petroleum coke were also encased in an inert vitreous slag.

Operational

- Over the course of the demonstration, the IGCC unit operated on coal for over 15,000 hrs, processed over 1.5 million tons of coal, and produced over 23 trillion Btu of syngas and 4 million MWh of electricity.
- Design changes in the first year included: (1) using a less tenacious refractory in the second-stage gasifier and changing the flow path geometry to eliminate ash deposition on the second-stage gasifier walls and downstream piping; (2) changing to improved metallic candle filters to prevent particulate breakthrough in the hot gas filter; and (3) installing a wet chloride scrubber and a COS catalyst less prone to poisoning to eliminate chloride and metals poisoning of the COS catalyst.
- The second year identified cracking in the gas turbine combustion liners and tube leaks in the heat recovery steam generator (HRSG). Resolution involved replacement of the gas turbine fuel nozzles and liners and modifications to the HRSG to allow for more tube expansion.
- The third year was essentially trouble free and the IGCC unit underwent fuel flexibility tests, which showed that the unit operated trouble free, without modification, on a second coal feedstock, a blend of two different Illinois #6 coals, and petroleum coke. Overall thermal performance actually improved during petroleum coke operation, increasing plant efficiency from 39.7% to 40.2%.
- In the fourth year, the gas turbine incurred damage to the rotor and stator in rows 14 through 17 of the air compressor causing a 3-month outage. But over the four years of operation, availability of the gasification plant steadily improved reaching 79.1% in 1999.

Economic

- The overall cost of the IGCC plant was $417 million, which equates to about $1,590/kW in 1994 dollars. For an equivalent greenfield project the cost was estimated at $1,700/kW. Capital cost estimates for a new 285 MWe (net) greenfield IGCC plant incorporating lessons learned, technology improvements, and a heat rate of 8,526 Btu/kWh are $1,318/kW (2000$) for a coal-fueled unit and $1,260 (2000$) for a petroleum coke-fueled unit.

Project Summary

The Wabash River Coal Gasification Repowering Project repowered a 1950s vintage pulverized coal-fired plant, transforming the plant from a nominally 33% efficient, 90-MWe unit into a nominally 40% efficient, 262-MWe (net) unit. Cinergy, PSI's parent company, dispatches power from the project, with a demonstrated heat rate of 8,910 Btu/kWh (HHV), second only to their hydroelectric facilities on the basis of environmental emissions and efficiency.

Beyond the integration of an advanced gasification system, a number of other advanced features contributed to the high energy efficiency. These included: (1) hot/dry particulate removal to enable gas cleanup without heat loss, (2) integration of the gasifier high-temperature heat recovery steam generator with the gas turbine-connected HRSG to ensure optimum steam conditions for the steam turbine, (3) use of a carbonyl sulfide (COS) hydrolysis process to enable high-percentage sulfur removal, (4) recycle of slag fines for additional carbon recovery, (5) use of 95% pure oxygen to lower power requirements for the oxygen plant, and (6) fuel gas moisturization to reduce steam injection requirements for NO_x control.

Over the four-year demonstration period starting in November 1995, the facility operated on coal for more than 15,000 hours and processed over 1.5 million tons of coal to produce more than 23 trillion Btu of syngas. For several of the months, syngas production exceeded one trillion Btu. By the end of the demonstration, the 262-MWe IGCC unit had captured and produced 33,388 tons of sulfur.

Operational Performance

The first year of operation resolved problems with:
(1) ash deposition on the second stage gasifier walls and downstream piping, (2) particulate breakthrough in the hot gas filter system, and (3) chloride and metals poisoning of the COS catalyst. Modifications to the second-stage refractory to avoid tenacious bonds with the ash and to the hot gas path flow geometry corrected the ash deposition problem. Replacement of the ceramic candle filters with metallic candles proved to be largely successful. A follow-on metallic candle filter development effort ensued using a hot gas slipstream, which resulted in improved candle filter metallurgy, blinding rates, and cleaning techniques. The combined effort all but eliminated downtime associated with the filter system by the close of 1998. Installation of a wet chloride scrubber eliminated the chloride problem by September 1996 and use of an alternate COS catalyst less prone to trace metal poisoning provided the final cure for the COS system by October 1997.

The second year of operation identified cracking problems with the gas turbine combustion liners and tube leaks in the HRSG Replacement of the fuel nozzles and liners solved the cracking problem. Resolution of the HRSG problem required modification to the tube support and HRSG roof/penthouse floor to allow for more expansion.

By the third year, downtime was reduced to nuisance items such as instrumentation-induced trips in the oxygen plant and high-maintenance items such as replacement of high-pressure slurry burners every 40–50 days. In the third year, the IGCC unit underwent fuel flexibility tests. The unit operated effectively, without modification or incident, on a second coal feedstock, a blend of two different Illinois #6 coals, and petroleum coke (petcoke). These tests added to the fuel flexibility portfolio of the gasifier, which had previously processed both lignite and subbituminous coals during its earlier development. The overall thermal performance of the IGCC unit actually improved during petcoke operation. The unit processed over 18,000 tons of high-sulfur petcoke and produced 350 billion Btu of syngas. There was a negligible amount of tar production and no problems were encountered in removing the dry char particulate despite a higher dust loading. Exhibit 3-45 provides a summary of the thermal performance of the unit on both coal and petcoke.

The fourth year of operation was marred by a 3-month outage due to damage to the rotor and stator in rows 14 through 17 of the gas turbine air compressor. However, over the four years of operation, availability of the gasification plant steadily improved, reaching 79.1% in 1999. Exhibit 3-46 provides a summary of the production statistics during the demonstration period.

Environmental Performance

The IGCC unit operates with an SO_2 capture efficiency greater than 99%. As a result, SO_2 emissions are consistently below 0.1 lb/10^6 Btu of coal input, reaching as low as 0.03 lb/10^6 Btu. Moreover, the process transforms sulfur-based pollutants into 99.99% pure sulfur, a highly valued by-product, rather than a solid waste.

Moisturizing the syngas in combination with steam injection reduced NO_x emissions to the 0.15 lb/10^6 Btu requirement established by EPA for existing plants in ozone non-attainment areas. Because of the extreme particulate filtration necessary for combustion of the syngas in a gas turbine, particulate emissions were negligible, averaging

Exhibit 3-45
Wabash Thermal Performance Summary

	Design	Actual	
	Coal	Coal	Petcoke
Nominal Throughput, tons/day	2,550	2,450	2,000
Syngas Capacity, 10^6 Btu/hr	1,780	1,690	1,690
Combustion Turbine, MWe	192	192	192
Steam Turbine, MWe	105	96	96
Auxiliary Power, MWe	35	36	36
Net Generation, MWe	262	261	261
Plant Efficiency, % (HHV)	37.8	39.7	40.2
Sulfur Removal Efficiency, %	>98	>99	>99

0.012 lb/10^6 Btu. Also, carbon monoxide emissions were quite low, averaging 0.05 lb/10^6 Btu.

The ash component of the coal results in a low-carbon vitreous slag, impervious to leaching and valued as an aggregate in construction or as grit for abrasives and roofing materials. Also, the trace metal constituents in the petcoke were effectively captured in the slag produced.

Economic Performance

The overall cost of the IGCC demonstration plant was $417 million, which equates to about $1,590/kW in 1994 dollars. For an equivalent greenfield project, allowing for additional new equipment required, the installed cost was estimated at $1,700/kW. Costs include engineering, permitting, equipment procurement, project and construction management, construction, start-up, and hiring and training personnel.

In the final report, the participant estimates capital cost for a new 262-MWe greenfield IGCC plant incorporating lessons learned, technology improvements, and a heat rate of 8,250 Btu/kWh are $1,275/kW (2000$) for a coal-fueled unit and $1,150/kW (2000$) for a petroleum coke-fueled unit. In designing for petcoke, some equipment can be reduced in size and some eliminated.

More recent data developed by DOE shows that a 285-MWe (net) coal-fired greenfield IGCC plant with a heat rate of 8,526 Btu/kWh would cost $1,318/kW (2000$). A 291-MWe (net) petroleum coke-fired IGCC unit with a 8,400 Btu/kWh heat rate would cost $1,260/kW.

Annual fuel costs for the Wabash project ranged from $15.3–19.2 million, with an annual availability of 75% and using high-sulfur bituminous coal ranging from $1.00–1.25/$10^6$ Btu ($22–27/ton). Non-fuel operation and maintenance (O&M) costs for the syngas facility (excluding the power block) was 6.8% of installed capital based on 75% availability. O&M costs include operating labor and benefits, technical and administrative support on and off site, all maintenance, chemicals, waste disposal, operating services, supplies, and 5% of the total O&M cost for betterments. Projected O&M costs for a mature IGCC facility (including the power block) are 5.2% of installed capital.

Exhibit 3-46
Wabash River Coal Gasification Repowering Project Production Statistics

Time Period	On Coal (Hr)	Coal Processed (tons)	On Spec. Gas (10^6 Btu)	Steam Produced (10^6 lb)	Power Produced (MWh)	Sulfur Produced (tons)
Start-up 1995	505	41,000[a]	230,784	171,613	71,000[a]	559
1996	1,902	184,382	2,769,685	820,624	449,919	3,299
1997	3,885	392,822	6,232,545	1,720,229	1,086,877	8,521
1998	5,279	561,495	8,844,902	2,190,393	1,513,629	12,452
1999[b]	3,496	369,862	5,813,151	1,480,908	1,003,853	8,557
Overall	15,067	1,549,561	23,891,067	6,383,767	4,125,278	33,388

[a]Estimates.
[b]The combustion turbine was unavailable from 3/14/99 through 6/22/99.

Commercial Applications

At the end of the demonstration in December 1999, Global Energy, Inc. purchased Dynegy's gasification assets and technology. Global Energy is marketing the technology under the name "E-Gas Technology™." The project is continuing to operate in commercial service as Wabash River Energy, Ltd., a subsidiary of Global Energy.

The immediate future for E-Gas Technology™ appears to lie with both foreign and domestic applications where low-cost feedstocks such as petroleum coke can be used and co-production options are afforded—bundled production of steam, fuels/chemicals, and electricity. Integration or association with refinery operations are examples. Factors favoring increased use of IGCC over time are continued improvement in IGCC cost and performance, projected increases in price differentials between coal and gas, and continued importance placed on displacement of petroleum in chemicals and fuels production.

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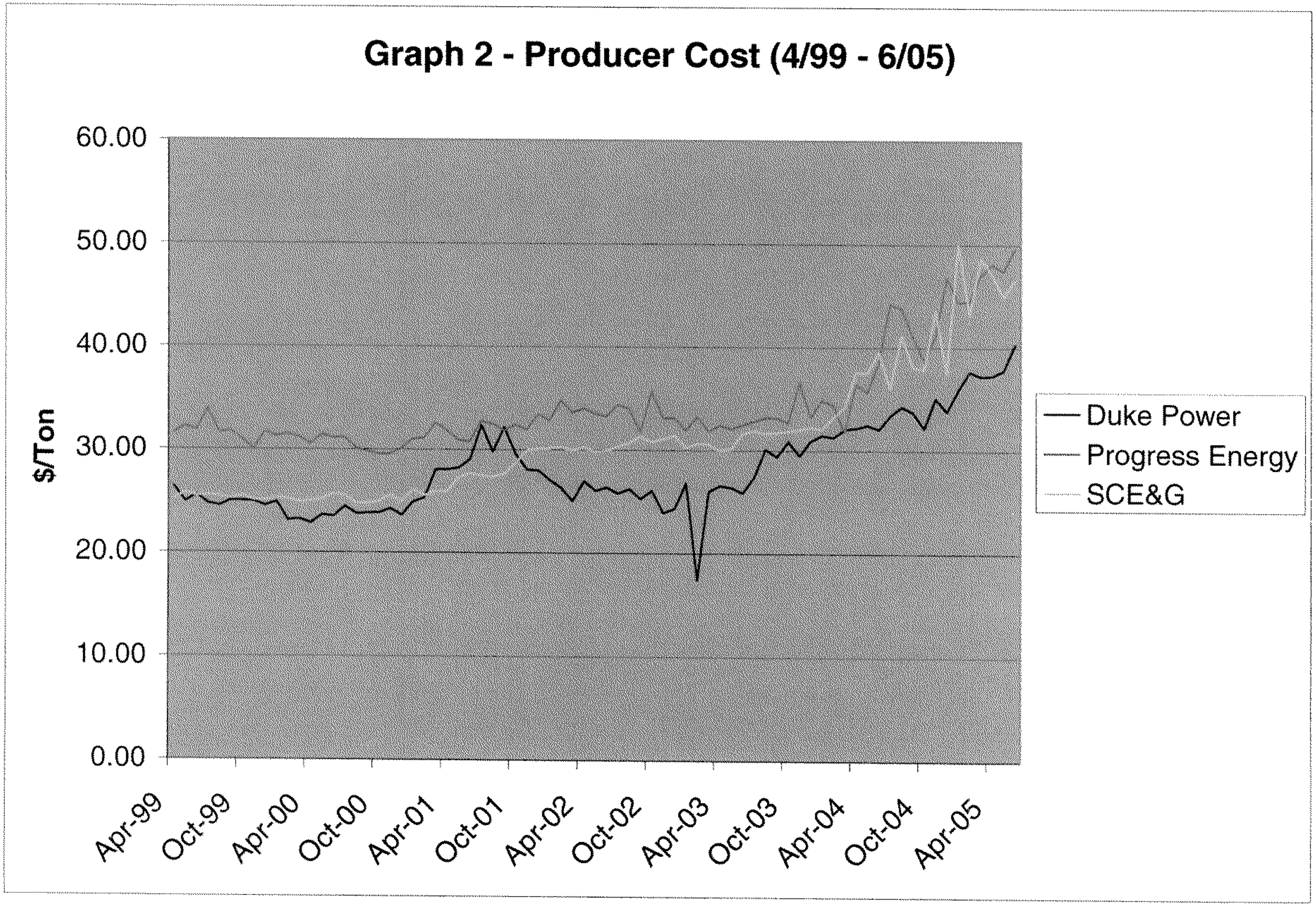
References

Wabash River Coal Gasification Repowering Project: Final Technical Report. Wabash River Coal Gasification Project Joint Venture. August 2000.

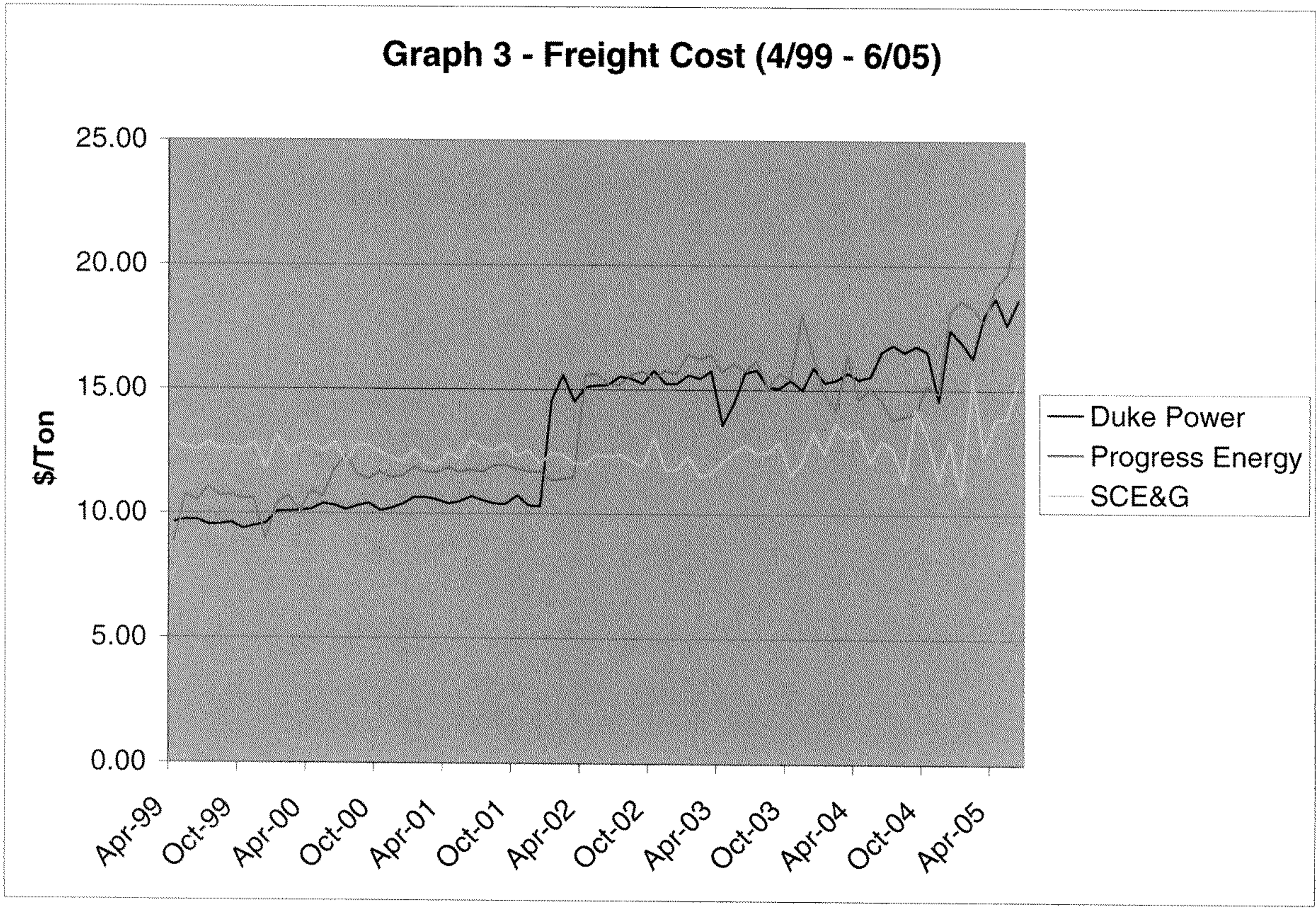
Wabash River Coal Gasification Repowering Project—Project Performance Summary. U.S. Department of Energy. January 2002.

ATTACHMENT F

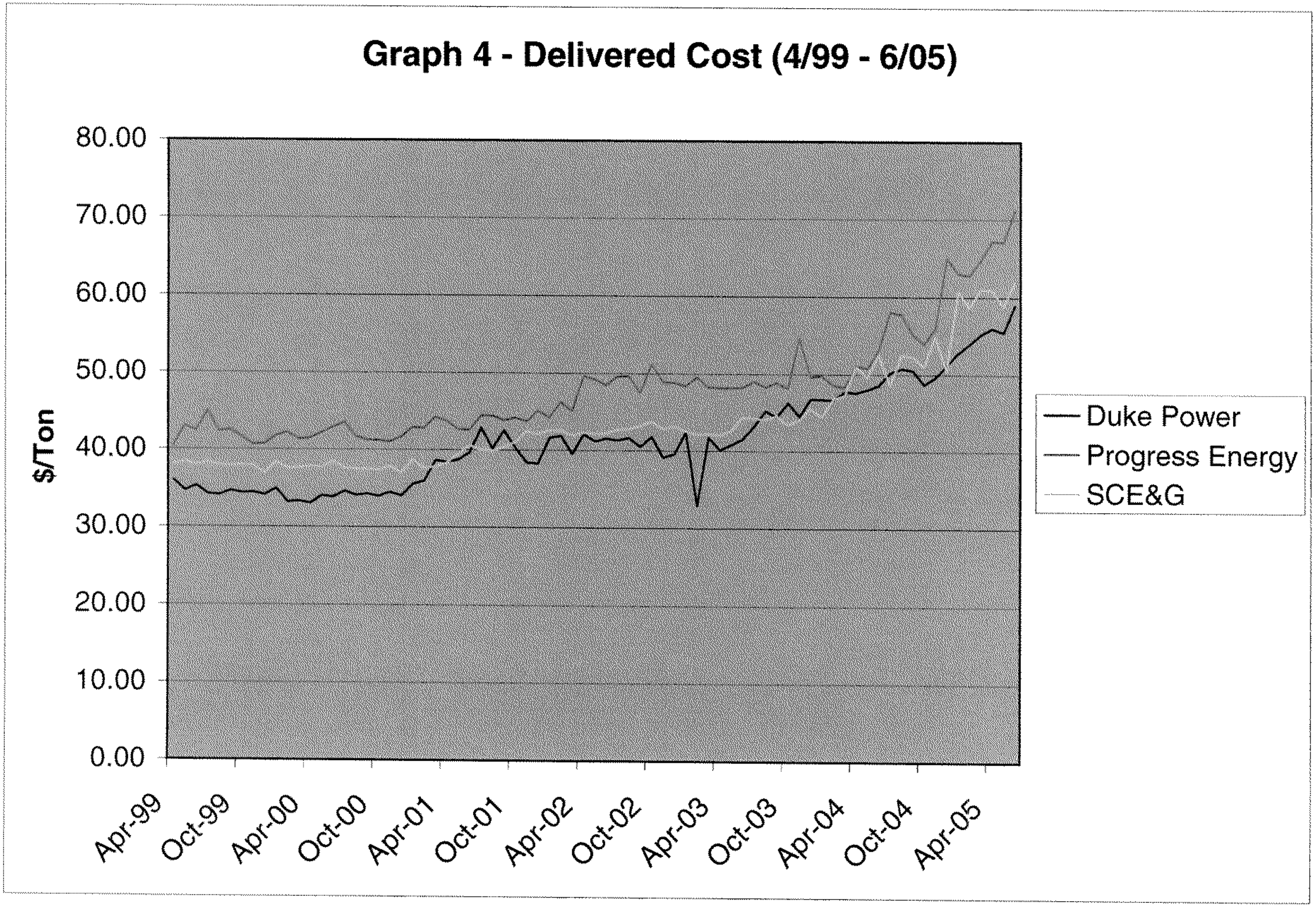


Graph 2 - Producer Cost (4/99 - 6/05)
60.00
50.00
40.00
30.00
20.00
10.00
0.00
$/Ton
Apr-99
Oct-99
Apr-00
Oct-00
Apr-01
Oct-01
Apr-02
Oct-02
Apr-03
Oct-03
Apr-04
Oct-04
Apr-05
Duke Power
Progress Energy
SCE&G

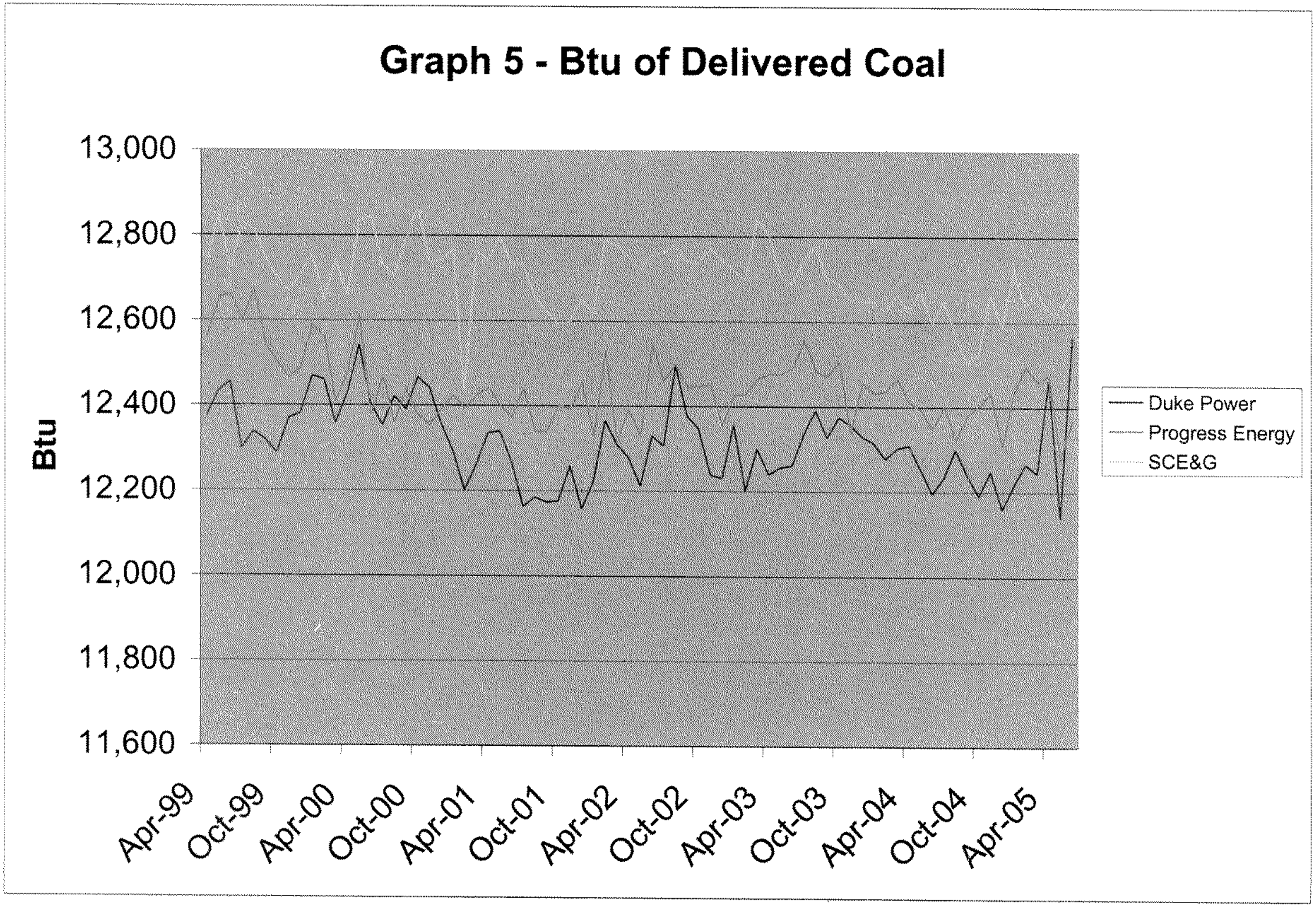
ATTACHMENT G


Graph 3 - Freight Cost (4/99 - 6/05)
25.00
20.00
15.00
10.00
5.00
0.00
$/Ton
Apr-99
Oct-99
Apr-00
Oct-00
Apr-01
Oct-01
Apr-02
Oct-02
Apr-03
Oct-03
Apr-04
Oct-04
Apr-05
Duke Power
Progress Energy
SCE&G

ATTACHMENT H


Graph 4 - Delivered Cost (4/99 - 6/05)
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
$/Ton
Apr-99
Oct-99
Apr-00
Oct-00
Apr-01
Oct-01
Apr-02
Oct-02
Apr-03
Oct-03
Apr-04
Oct-04
Apr-05
Duke Power
Progress Energy
SCE&G

ATTACHMENT I


Graph 5 - Btu of Delivered Coal
13,000
12,800
12,600
12,400
12,200
12,000
11,800
11,600
Btu
Apr-99
Oct-99
Apr-00
Oct-00
Apr-01
Oct-01
Apr-02
Oct-02
Apr-03
Oct-03
Apr-04
Oct-04
Apr-05
Duke Power
Progress Energy
SCE&G

ATTACHMENT J

SC ELECTRIC AND GAS COMPANY FUEL STUDY
INVENTORY TRACKING (TONS)
REVIEW PERIOD: (1/1/2005 – 12/31/2005)

REDACTED

SC ELECTRIC AND GAS COMPANY FUEL STUDY
INVENTORY TRACKING (TONS)
REVIEW PERIOD: (1/1/2006 – 12/31/2006)

REDACTED